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QUANTIFYING REMAINING OIL SATURATION USING SEISMIC TIME-LAPSE AMPLITUDE CHANGES AT FLUID CONTACTS

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ABSTRACT

Our study shows that time-lapse changes in the amplitude of the seismic reflection at an oil-water contact and/or produced oil-water contact can be used to directly estimate the displacement efficiency of water displacing oil, E_D without the need of a rock and fluid physics model. From this value it is possible to determine the remaining oil saturation if required. A preliminary application is performed using several published literature examples, which are re-interpreted to assess the average E_D and ensure the theory is consistent with expectations. Next, a North Sea field model with a known E_D is used to create fluid flow predictions and the corresponding synthetic time-lapse seismic data. Application to these data again confirms the basic principles of the method and defines the accuracy when applied to 4D seismic data. Finally, an observed 4D seismic dataset from a producing field in the North Sea is analysed. The results suggest a displacement efficiency of between 21 and 65% with an accuracy of 3% due to data non-repeatability (with a NRMS of between 11 and 13%). Given an average irreducible water saturation of 0.32 this calculates remaining oil saturations between 24% and 53% for this field. A pre-requisite for use of the proposed oil-water contact approach is that a discrete contact be interpreted on either the 3D or 4D seismic datasets. Therefore successful application of this technique requires moderate to high quality seismic data and a fairly thick reservoir sequence without significant structural complexity.

INTRODUCTION

In this work, we consider the evaluation of the oil saturation left behind in a hydrocarbon reservoir, after oil is displaced by water as a consequence of natural drive oil production, or production supported by water injection in the oil leg. This is an important objective for reservoir monitoring and surveillance, and understandably much effort has gone into the study of this topic in the published reservoir engineering literature over the past fifty years (Al-Harbi et al. 2011). Remaining oil saturation (ROS)* values impact our understanding of the reservoir's recovery factor - a key parameter that defines the strategy for production optimisation. The distribution of ROS determines the sweep efficiency of the water displacement due to either edge or bottom water mechanisms (Dake, 2001). More generally, it identifies possible zones of un-swept, bypassed oil for future drilling, and also the amount of oil left behind in the swept zone after production. The exact location and amount of ROS needs to be understood in order to assess the feasibility for enhanced oil recovery methods (such as miscible gas injection, water alternating gas, polymer flooding, and surfactants) to further mobilise and extract the remaining oil. From a production perspective, knowledge of ROS is important for material balance, calculating production forecasts, and is an essential input for the numerical simulation model.

There are many factors, acting at the microscopic (pore scale) and mesoscopic (outcrop) or macroscopic (reservoir/field) scale, that affect the magnitude of ROS. At the smallest scale, residual oil trapped within the pore space is immobilised by capillary forces under flow conditions (Figure 1(a)). This residual oil saturation (S_{orw}) defines one of the end-points of the relative permeability of oil to water, and is the point at which oil no longer flows and oil is trapped by the invading water. This behaviour depends on a range of rock and fluid dependent factors, such as mineralogy, pore size distributions, texture, geometry, roughness, clay content, and oil and formation water composition. At this pore-scale, the wetting behaviour of the rocks has also been identified to be of particular importance. For example, research by Skauge and Ottsen (2002) has shown that S_{orw} in core flooding experiments decreases significantly when we move from a water-wet to an oil-wet reservoir (for example, S_{orw} moves from 0.45 to 0.04). *ROS* at the mesoscopic or macroscopic scale are principally controlled by the geological heterogeneity (Figure 1(b)), and hence are strongly related to the depositional environment. Clearly, ROS at the mesoscopic/macroscopic scale is greater than pore-scale S_{orw} in a fully swept region of the reservoir. Important factors controlling the value of *ROS* at mesoscopic/macroscopic scale include the degree of diagenesis, cementation, and trapping mechanisms such as laminae or cross-bedding (Pickup and Hern 2002). Faults, fractures, and stratigraphic barriers also require consideration. Finally, at the field (macro)-scale (Figure 2), zones of unswept (bypassed) oil can be identified. Unswept zones may exist due to a diversion of the water displacement process, such as fingering and inter-bedding or diversion at a barrier or faulted structure. Such bypassed areas are still in the initial oil saturation state and represent opportunities for *IOR* through in-fill drilling, better project management, or by a change in the depletion strategy such as production rate reductions. Such bypassed areas have been successfully identified from conventional application of techniques such as 4D seismic (see below). Importantly, within the swept zone there is oil not recovered by the water displacement mechanism and this represents a potential EOR target as discussed above. The focus of this current study to extend the 4D seismic technique with the goal of identifying remaining oil saturations in a practical manner that does not require a detailed rock and fluid physics study.

Measurement of ROS from engineering practice

Current methods to measure *ROS* range from laboratory experiment to open hole, and repeated cased-hole wireline or production logging. Teklu et al. (2013) provides a review of these methods. Laboratory core flooding tests are commonly used: where a rock sample in the shape of a cylinder is extracted from the reservoir, saturated with oil and then this is displaced by water or gas. Other types of measurement include centrifuge experiments, which establish the true residual oil saturation from the lowest achievable capillary pressure when no further oil displacement is possible under capillary dominated flow conditions. Well measurements can also be made using tools that measure oil saturation in reservoir zones that produce only water. However there is some uncertainty associated with these measurements. For example, resistivity techniques are difficult to interpret in a mixed salinity (formation and injected water) environment, or in mixed sand-shale lithologies. Single well chemical tracer tests can also provide a way of estimating the concentrations of injected water, and hence residual oil values. Another, more recent development, is the use of pore network models, calibrated from digital CT images to numerically compute the flow physics and hence relative permeabilities (Ryazanov 2012). Despite a range of methods available to measure ROS, it is observed that a generally accepted way to predict ROS across the field and between the wells does not exist, as it is difficult to capture the field variations with measurements based at the wellbore (Pathak et al. 2012). No single measurement achieves a definitive result, and a combination in an integrated study provides the most satisfactory way of assessing the oil in place (Pathak et al. 2012). At the field scale, a whole reservoir average measurement can be provided by material balance and production analysis (Sharma and Kumar 1996). Finally, numerical simulation provides the best current approach to capture areal and vertical variations, and the field production-scale values (for example, Rao et al. 2013). However most approaches underestimate ROS as they do not adequately capture heterogeneity and use conservative input values of ROS (Valenti et al. 2002). Overall, values of ROS have been quoted as low as 0.04 and as high as 0.45, for both carbonate and clastic reservoirs (Vrachliotis 2012, Skauge and Ottsen 2002).

ROS determined from seismic data

The use of 3D seismic data for reservoir management is well established, through the interpretation of reservoir structure (faults and major bounding surfaces of the reservoir flow units) and fluid contacts, which input directly into the determination of initial oil volumes in the reservoir once saturations and porosities have been assigned. The monitoring of reservoirs undergoing production and recovery using repeated seismic surveying (the 4D, or time-lapse, seismic method) is now also firmly established by numerous case studies over more than a decade (Jack, 1998; Johnston 2013). In particular, it has been demonstrated that water-flooding, and associated contact movements, are often visible in most 4D seismic data despite the overlapping effects of pressure, temperature, salinity, geomechanical effects and acquisition non-repeatability. Indeed, water saturation changes have been detected in acquisition non-repeatability conditions, ranging from excellent to poor (a normalised root mean square metric of between 5% and 40% respectively), both in onshore and offshore data, and for clastic (Marsh et al. 2003), chalk (Byerley et al. 2006) and hard rock carbonate reservoirs (Al-Jenaibi et al. 2006). The principal use of such information to date has been to identify economic in-fill targets created by bypassed pockets of mobile oil due to unexpected water flow (Koster et al. 2000) or compartmentalisation (Staples et al. 2006). Other uses of 4D seismic data include evaluation of injector performance and subsequent intervention (Roeste et al. 2009) and simulation model updating (Oliveira 2008; Gonzalez-Carballo et al. 2006). Less commonly mentioned, is the need to estimate an accurate value of the ROS within the already water-swept zones (Johnston 2013; Alvarez & MacBeth 2014; Obiwulu and MacBeth, 2015) which impacts the economical evaluation of the displacement process and underpins future EOR strategies. A thorough quantitative analysis of the 4D seismic data must draw a link between the magnitude of the 4D seismic signature and the remaining oil saturations, and is the topic of this study.

THE 4D SEISMIC SIGNATURE OF AN OIL-WATER CONTACT MOVEMENT DURING PRODUCTION

In this work we attempt to estimate remaining oil saturation by monitoring the original and produced oil-water contacts from oil reservoirs depleting with natural basal aquifer drive or with support from water injectors. We examine the steady upward rise of a horizontal oil-water contact through bottom water influx, and determine the magnitude of the fluid contact reflectivity before and after production using 4D seismic data. The technique is suited to reservoirs in which the pre- and post-production fluid contacts are visible on the seismic data, and these contacts exhibit a detectable upward movement. Selected field examples of such reservoirs in the published literature include Gannett C (Kloosterman et al. 2001), Nelson (McInally et al. 2001, MacBeth et al. 2005), and Alba (Tura et al. 2009), all of them from the North Sea. Seismic visibility of the contacts requires a reasonably thick reservoir sequence, with good vertical connectivity and a mechanism for basal water drive.

The process of bottom water influx is simplified for our calculations as shown in Figures 3(a) and 3(b). Here, we neglect the thickness of the transition zone between the oil leg (with irreducible water saturation) and the free water level (at 100% water saturation) relative to the vertical movement of the water contacts and overall thickness of the reservoir. We also collapse both the oil-water contact and free water level into one single discrete interface that we define generically as the 'oil-water contact'. Our simple 'seismic' model therefore assumes that the initial oil zone is saturated by water at the irreducible water saturation S_{wirr} (the saturation below which water cannot flow), and ignores the fact that the initial water saturation of the undisturbed reservoir prior to production may contain formation water that may also be produced with the oil. In this model, we also neglect the fluid pressure changes, as calculations show these are a factor of 10 smaller compared to the saturation changes

(Alvarez & MacBeth 2014). The production state is represented by the creation of an additional 'produced oil-water contact'. These assumptions above are all justifiable for seismic analysis purposes provided the vertical permeability of the reservoir is relatively high (> 100 mD), the API gravity of the oil (API >30) is also high, and the seismic wavelength is long (larger than the transition zone). However as in practice transition zones can vary from a few metres to several hundred metres depending on the reservoir and the specific capillary pressure curves (Ahmed 2006), the applicability of this model must be examined on a case-by-case basis. A final assumption for our theoretical development is that both the original and produced contacts are planar and horizontal, and therefore that the vertical connectivity is uniform – this is rarely the case for an actual reservoir, due to hydrodynamic gradients and geological heterogeneity. Furthermore, the seismic data could experience seismic travel-time variations that would prevent the contacts from appearing flat in two-way time.

The original oil-water contact is visible in the seismic data as a reflection in the baseline (pre-production) data due to the fluid property contrasts between the oil leg (oil and irreducible water) and the water leg (100% water saturation) (see Figure 3(a)). This contrast may, or may not, be large, depending on the oil gravity – the lighter the oil, the stronger the contrast. During production, as the oil-water contact moves upwards it sweeps through the oil column (see Figure 3(b)). The oil saturation remaining after this process will depend on the many factors outlined in the previous section. There is now a seismic contrast between the un-swept oil leg (oil and the irreducible water saturation) and the swept zone (remaining oil, invading water, and irreducible water component), and also between the swept zone and the water leg with 100% water (MacBeth et al. 2005). These contrasts lead to seismic reflections at the original and produced oil-water contacts (*OOWC* and *POWC* respectively), the magnitudes of which vary according to the remaining oil. If the two-way time difference is large enough to separate these individual reflections, then their amplitude can be used as a measure of the remaining oil saturation as described below.

Reflectivity changes at the fluid contacts

For the model and assumptions defined in the previous section, the *P-P* wave reflection coefficients for the *OOWC* or *POWC* depend predominantly on the saturation conditions above and below the contacts provided there are no significant facies changes across the contact boundary. This condition has implications for the variation of the reflection coefficient *R* with incidence angle θ at each fluid-fluid interface within the same porous rock. Some of these characteristics have been explored by Wright (1986) in a previous theoretical development based on the fluid substitution theory of Gassmann (1951) and the reflection coefficient approximations of Shuey (1985). This work showed that the *P-P* amplitude variation with θ in the case of fluid-fluid contacts takes a simple form. He concluded that reflection coefficients *R(θ)* at gas-brine, gas-oil or oil-brine contacts (that are all naturally positive at normal incidence) always increase monotonically with θ - i.e. become brighter and more positive with angle/offset. To first order in impedance, and for small density contrasts (less than 10%), this increase is found to be independent of V_P/V_S and is given by:

$$R(\theta) = R_0(1 + sin^2\theta), \tag{1}$$

The reflectivity is thus controlled by the normal incidence reflection coefficient R_0 scaled by an angle-dependent factor. This behaviour is also confirmed for our current study in Figures 4(a) and (b), which plot the reflection coefficients for a range of fluid saturation jumps across the original oil-water contact and produced oil-water contact against $(1 + sin^2\theta)$ for angles up to 30^o. Despite the exact reflection coefficients (coloured curves in Figure 4) being calculated here using the plane-wave equations cited in Aki and Richards (1980) (also see Zoeppritz, 1919), and not small contrast approximations as in Wright (1986), the trend identified is still broadly valid (compare the dotted linear approximations and dashed quadratic approximations with the coloured exact solutions). We also observe that the reflection coefficients for the oil-water contacts are typically in the range 0.01 to 0.10. Such magnitudes are also noted by Marsh et al. (2003) for a wide range of North Sea fields. To develop these findings further for our desired objective of estimating *ROS*, we firstly write the P-wave impedance as a function of the water saturation S_w introduced into an initially oil-filled reference rock

$$I(\mathrm{S_w}) = \mathrm{I_0}(1 + \mathrm{aS_w} + \mathrm{b}S_w^2), \tag{2}$$

where I_0 is the impedance for the saturation state of $S_w = \mathrm{S_{wirr}}$, and the terms in parentheses give the departure from this reference saturation state. We approximate the impedance by a quadratic function, and find this to be reasonable for most fields analysed to date (Alvarez 2014, Mavko, et al. 1998). The coefficients *a* and *b* are determined theoretically by a Gassmann fluid substitution exercise for a range of initial rock and fluid conditions. The alternative of calibrating by regression to laboratory data would involve a representative sample initially saturated with oil, and therefore would be difficult to obtain in practice. From the above and following Alvarez & MacBeth (2014), the angle-dependent reflection coefficient $\mathrm{R}(\theta)$ can be calculated to first order

$$\mathrm{R}(\theta) \approx a \; \Delta \mathrm{S_w} \left\{\frac{1}{2}\, sec^2\theta\right\}, \tag{3}$$

where ΔS_w is the contrast in water saturation across the interface. We neglect the higher order terms in the saturation change for now, as they contain complicated combinations of a, b, S_{wirr} and *ROS* and do not lead to intuitive results that may be easily applied in practice. The full analytic expressions for the coefficient a are shown in Appendix A. Figures 4(a) and (b) show that the linear approximation in (3) agrees with the full numerical computation from the Zoeppritz result to a reasonable degree. For reference, the slightly more accurate approximations with the quadratic ΔS_w term are also shown. Importantly, (3) predicts a relatively uniform spacing of R(θ) with ΔS_w for any fixed offset/incidence angle, which has implications for the practical understanding of the fluid contact reflectivity, and we therefore continue with the seismic data development using this linear approximation.

In our model of contact movement, as the oil-water contact moves upward through the oil column it leaves behind the remaining oil saturation *ROS* in the water-swept zone. The seismic reflection from the original *OWC* (*OOWC*) location still remains after this contact movement but will be diminished. The reduction is also related to the emergence of the produced *OWC (POWC)*. To quantify this relationship, (3) is applied to the angle-dependent reflection coefficients (or migrated amplitudes from angle-stacks) prior to water sweep, giving

$$\mathrm{R}_{OOWC}^{before} \approx a\,(1 - \mathrm{S_{wirr}}) \tag{4}$$

and

$$\mathrm{R}_{POWC}^{before} = 0 \tag{5}$$

where S_{wirr} is the irreducible water saturation in the oil-saturated portion of the reservoir, R_{OOWC}^{before} and R_{POWC}^{before} are the reflection coefficients of the original and produced oil-water contacts interpreted in the pre-production baseline. After movement of the oil-water contact (monitor), the reflection coefficients are now

$$\mathrm{R}_{OOWC}^{after} \approx a\, ROS \tag{6}$$

and

$$\mathrm{R}_{POWC}^{after} \approx a' \,(1 - ROS - \mathrm{S}_{\mathrm{wirr}}) \tag{7}$$

Where a and a' are defined in Appendix A (equations A8 and A9). In these equations, we neglect the fluid pressure changes, since these are small compared to the saturation changes (Alvarez & MacBeth 2014), which is a valid assumption when working above the oil bubble point pressure (as there is no liberated gas).

Inspection of these formulae reveals that if a baseline seismic dataset is acquired prior to contact movement, and a monitor dataset acquired after production-induced movement, then time-lapse changes in the reflection coefficients for the *OOWC* and *POWC* are proportional to the maximum water saturation change $(1 - ROS - \mathrm{S}_{\mathrm{wirr}})$, but of opposite sign – this observation in itself is a useful control when visually inspecting the seismic data for application of these equations. Furthermore, (6) indicates that the reflection coefficient at the *OOWC* after water sweep is directly proportional to *ROS*. Unfortunately, immediate practical use of the above equations as a direct indicator for *ROS* is masked by lateral variations in the reservoir rocks and the initial fluid conditions, the imprint of which is carried into the reflectivity via the spatially varying coefficients *a* and *a'*. In practice, wavelet scaling must also be considered when interpreting the amplitudes in the seismic volume. The scaling for each reflection coefficient cannot be independently determined using (2) to (5) as in general both *ROS* and S_{wirr} are uncertain. One approach is to assess the variability of *a* and *a'* theoretically (see, for example, Alvarez 2014 and Appendix 1). Alternatively, equations (5) and (6) do allow us to determine the much sought after mesoscopic/macroscopic displacement sweep efficiency, E_D, defined by the ratio of $(1 - \mathrm{S_{wirr}} - ROS)$ and $(1 - \mathrm{S_{wirr}})$; this can be obtained directly from the seismic data by taking a ratio of the reflection amplitudes (on the assumption of adequately cross-equalised seismic data)

$$E_D = \frac{\mathrm{R}_{POWC}^{after}}{\mathrm{R}_{OOWC}^{before}} \approx c\ \frac{1-\mathrm{S_{wirr}}-ROS}{1-\mathrm{S_{wirr}}}, \tag{8}$$

This requires picking the *POWC* on the monitor seismic data and the *OOWC* on the baseline seismic data, and evaluating the constant *c* which is a function of the fluid compressibility - typically a value between 0.85 and 0.95 (Appendix A). Alternatively, only the *OOWC* may be picked, and the reflection amplitude before and after production used to determine

$$\frac{\mathrm{R}_{OOWC}^{after}}{\mathrm{R}_{OOWC}^{before}} \approx \frac{ROS}{1-\mathrm{S_{wirr}}}, \tag{9}$$

or the sweep efficiency

$$E_D = \frac{\mathrm{R}_{OOWC}^{before} - \mathrm{R}_{OOWC}^{after}}{\mathrm{R}_{OOWC}^{before}} \approx \frac{1-\mathrm{S_{wirr}}-ROS}{1-\mathrm{S_{wirr}}} \tag{10}$$

which requires the picking of only one contact on the seismic volume (the most visible) and is therefore less time consuming.

The sweep displacement efficiency, E_D, is a general quality indicator for the water-flood progression, and is a useful metric to extract from the seismic data (Obiwulu and MacBeth 2015). Such information is important when assessing a water injection programme and remaining reserves, and for modifying support strategy for sweep optimisation. However, if it is necessary to obtain an estimate of *ROS* directly from seismic data using the equations above, accurate knowledge of S_{wirr} and its distribution across the reservoir is required. Initial water saturation may be obtained by the analysis of resistivity logs, combined with estimates of porosity and capillary pressure curves from coreflooding and other measurements that lead to saturation height functions. If there is sufficient confidence in these estimates, then *ROS* can be obtained from either (8) or (10). However, if S_{wirr} is not known with any more accuracy than *ROS* (as is the case when no core measurements or water samples are available), one alternative is to link both parameters together in a common estimate. This relies on the fact that the initial water-wet state is strongly influenced by rock texture, which in turn is controlled by the depositional environment – suggesting a common origin for the rock and fluid physics. Thus, fine grained (lower permeability) sediments usually characteristic of low energy depositional environments tend to have high S_{wirr}, and coarse grained (higher permeability) sediments from high energy environments, tend to have low S_{wirr}. Complementarily, ROS is known (Humphry, et al., 2013) to be a function of wettability rather than of pore structure, as the wettability influences how oil is trapped and controls the capillary forces required to remobilize the oil. In general, ROS is expected to be lower in strongly water-wet systems (high S_{wi}) and slightly higher in strongly oil-wet systems (low S_{wi}). Note that, the lowest ROS is found in mixed-wet rocks and large pores, whereas in small pores the above trends are generaly weak (Skauge and Ottesen,2002). Additionally, there is some evidence (Maldal, et al. 1998) that a linear relationship exists between the initial oil saturation (hence irreducible water saturation) and remaining oil saturation in both clastic (Davies et al. 1993) and carbonate (Verma et al. 1994, Masalmeh 2002) reservoirs. With a linear relation between the two quantities defined from other core or log data, it is then possible to use (9) and (10) to determine S_{wirr} and *ROS* together.

In cases where the first order approximation for R_0 as in (3) is not valid, such as reservoirs close to the bubble point or when multiple fluid phases interact in reservoirs close to the seismic tuning thickness, higher order terms depend in a complicated way on a, b, S_{wirr} and *ROS*. Indeed, for our particular case study, Figures 4(a) and (b) show a decrease in the separation of the R(θ) curves with increasing water saturation. However calculations by Alvarez (2014) show that this decrease in separation is easily predictable in practice and varies depending on the contrast between the oil and water properties and the stiffness of the rock matrix. Second order terms contain differences and sums of the saturations, and direct simplification is not easily obtained or not particularly useful. Instead, to increase accuracy by capturing the variability of ROS, the most direct approach is to calculate the reflectivity ratios in (9) and (10) as a function of $1 - S_{wirr}$ and *ROS*. This approach will be used in the synthetic and observed examples in the sections below, which have been selected as they fall within the requirements of the assumptions of this study.

Literature example 1

To illustrate use of the approach outlined above, we initially consider two previously published examples. The first is from the Gullfaks field in the northern North Sea. This field is structurally complex, and consists of early to middle Jurassic age reservoirs from the Brent sequence. Despite the field complexity, there is a detectable water sweep in response to production and water injection, and a uniform rise of the oil-water contact in most reservoir units. As strong production effects are observed across the field, the 4D seismic is widely used as part of an IOR programme to detect un-depleted areas for infill drilling and to construct flooding maps (Talukdar and Instefjord 2008). Repeated saturation logs help calibrate the fluid movements and confirm the interpretations of fluid contacts observed on the 4D seismic data (El Ouair and Stronen 2006). Figure 5 shows the Top Tarbert formation (top reservoir) and the associated OOWC. The top reservoir dims significantly in response to increased water saturation, whilst the oil-water contact also dims substantially and there is the appearance of a produced oil-water contact. According to Maldal et al. (1998), the Tarbert reservoir rocks are mixed wet, with low viscosity oil in a thick oil zone, and good vertical communication. These conditions allow gravity effects to play a role in the recovery process, leading to a high recovery and low residual oil. Indeed, laboratory measurements have determined *ROS* values as low as 14% in the Tarbert and as low as 9% in the Etive. Based on coreflooding tests, the following relation exists for Gullfaks between the initial water saturation S_{wi} and the residual oil saturation to water sweep, S_{orw} (Maldal et al. 1998)

$$S_{orw} = -1.6\, S_{wi} + 0.7, \tag{11}$$

This gives $S_{wi} = 0.35$ for a residual oil saturation of 0.14. Applying (10) this leads to a displacement sweep efficiency of 78%. The small amplitude observed at the OOWC is consistent with this result.

Literature example 2

The second example is from the Gannet-C field in the Central North Sea. This consists of a rim of Tertiary-aged turbidite reservoirs, dip-closed around a piercing salt diaper. The sands of the Forties and Lower Tay formation are high porosity (28%), relatively clean and with a fraction of intra-reservoir shale stringers. There is a thick oil leg of 100 m overlain by a substantial gas cap (Kloosterman et al. 2003). The oil is light, with an API of 38^o. The seismic sections shown in Figure 6 are pre-production (1993) and after several years of production (1998). The first 4D seismic monitor was acquired to identify un-drained or bypassed hydrocarbons in reservoir compartments, sealing and non-sealing faults, and the efficiency of the drive mechanisms and connected volumes to specific wells (Staples et al. 2006). There is known to be good communication in the reservoir sands and reasonable aquifer support, leading to full contact rise in both the Forties and Lower Tay reservoirs. Additionally, the seismic data show clear and individual fluid-related reflections for the gas-oil and oil-water contact before and after production (Figure 6). Indeed, the fluid contacts are sufficiently clear for the contact heights to be used directly to history match the simulation model (Staples et al. 2006). Figure 6 shows a weak *POWC*, moderate dimming of the *OOWC* and an upward tilt of the *GOC*. The *OOWC* is visually estimated to dim by only 25%. Based on a conservative S_{wirr} of 0.20, (4) and (6) therefore give a *ROS* of 0.60, and (7) predicts that the *POWC* should be 1/4 of the reflection strength of the *OOWC* before production (assuming $a = a'$). From (10), the overall sweep displacement efficiency would therefore be 25%. The *ROS* estimate is much higher than those quoted by Koster et al. (2000) for the entire field, but is consistent with the relative reflection strengths for the fluid contacts in Figure 6. As Staples et al. (2006) mentions the disappearance of the *OOWC* after production on this field, there is the suggestion that much lower *ROS* values exist elsewhere.

Synthetic example

To evaluate our approach further in an ideal situation where the answer is already known and there is an absence of non-repeatability noise, processing artifacts and significant heterogeneity, we construct a simulation model loosely based on the Gannett-C field example in the previous section. The reservoir model parameters for this model are given in Table 2. For the reservoir scenario we choose two dipping juxtaposed sandstone reservoir units with mean sand porosities of 27% and 29% and net-to-gross of 0.70 and 0.90 respectively lying against a salt dome. Both porosity and net to gross are varied both vertically and laterally within each unit, using a geo-statistical model, and these lead to corresponding variations in S_{orw} from 0.18 to 0.37 and S_{wirr} from 0.12 to 0.15. In turn, this leads to an irregular produced oil-water contact and a variation in the displacement efficiency E_D within and along each unit. There are two producers in the field, and there are no injectors, The main production mechanism is edge aquifer drive and the wells receive good support from the aquifer. The resultant water, oil and gas saturations for fluid flow simulation before and after twelve years of production are shown in Figure 7. Figure 8 gives the resultant saturation changes, calculated displacement efficiency and residual oil saturation for a section through the model, which should be compared with the estimates from the seismic data. There is a pressure change from 20MPa to 19 MPa during production but this does not affect our results significantly. The synthetic seismic data are now created by applying the sequence of petroelastic transformation followed by convolutional modelling described in Amini and MacBeth (2011). The seismic data are calculated at the same scale as the simulation model cell, resulting in a trace spacing of 12.5m. The corresponding synthetic seismic sections are shown in Figures 9(a) and (b). Interestingly, although the top, base and intra-reservoir reflectors dominate the response, the flat spots associated with the contacts can still be detected in the separate baseline and monitor seismic sections. The anticipated dimming of the *OOWC* is apparent in the seismic data, together with the strong and obvious POWC varying in elevation above the OOWC by up to 60 m within each unit. The *OOWC* is picked on the baseline seismic data at a fixed depth location, and the *RMS* amplitude for the contact is determined using a 10 ms symmetric window. Equation (10) is then applied to determine the displacement efficiency from the seismic data (Figure 10(b)), and this is then compared with the model result in Figure 10(a). The results estimated from the seismic data agree fairly closely with the actual values, with an RMS error of 8% but rising in some places to 20%. Small differences between the seismic estimates and actual arise from errors due to the different way the model and the seismic sample the reservoir. The larger errors appear in regions where the reservoir thickness drops below tuning, and also where net to gross is low.

Field data example

The theory developed above is now applied to a central North Sea dataset that has readily identifiable oil-water contacts in both the baseline and monitor seismic data.

Background

The reservoirs in this field consist of a series of turbidite sand complexes deposited around a structural high associated with salt movement at depth (Staples et al. 2007). The structure is dip closed, and characterized by crestal faults. There are three reservoir packages, with the main Forties sandstone being the focus of attention in our study. This is chosen because it is good quality sandstone with a high net-to-gross of 90%, porosity of 26%, and average permeability of 600 mD. Importantly, the Forties reservoir thickness (mean of 34 m) is significantly above tuning thickness across most of the field. In addition, it is known from previous studies that water sweep is clearly visible in the Forties sandstone and that there is a good impedance contrast between the formation water and the light 37^{o} API oil. The 4D seismic data indicate that the field is produced largely by bottom drive, with the west of the field being particularly strongly swept by the aquifer. The impact of water replacing oil on pressure is believed to be minimal, due to good pressure support from regional aquifers (Lynn et al. 2014). However pressure support in the reservoir as a whole is weak due to shales and baffles, and the total depletion over thirteen years as measured in the wells is about 3MPa (450 psi). The reservoir pressure is still above the bubble point pressure. This leads to a slow upward movement of the oil-water contact over many years.

A pre-production base line was shot in 1997, followed by monitor seismic surveys in 2006 and 2010, nine and thirteen years after production. The seismic data repeatability is excellent with a normalized root mean square metric (Kragh and Christie 2002) for the final migrated 2006 - 2010 data of 11%, and 13% for 2006 - 1996. The field was originally developed in 1997 with one vertical well (W1 in Figure 11), which produced dry oil for nearly one year before starting to produce water, reaching up to 60% water cut by the time of the first monitor. A horizontal infill well (W2 in Figure 11) was then drilled in the Forties based on 4D seismic data (Staples et al. 2007). Surprisingly, W2 produced dry oil for about three years, much longer than W1, and by the time of the second monitor it still showed a low water cut of only around 20%. Special core analysis tests were taken in well W1, providing core-scale values for the irreducible water saturation S_{wirr} of 0.32 and a residual oil value S_{orw} of 0.22, or an E_D of 68%. It is known that as the Forties reservoir contains internal heterogeneity such as intra-reservoir shales, the field-scale measurement of E_D will be lower than this core-scale estimate.

Results of ROS calculation

Figure 11 shows seismic sections along a traverse through both wells W1 and W2 for the baseline and monitor times. In the Forties sandstone the original fluid contact is clearly visible in the pre-production base line seismic data (Figure 11(a)), and this is confirmed by well measurements. A clear dimming of the *OOWC* is observed over time, which becomes progressively dimmer when moving from the first to second monitor survey. There is a significant dimming to almost zero to the west, but to the east the dimming is less pronounced and the contact movement is small. The *POWCs* for monitor 1 and 2 are difficult to identify on the individual sections, but are quite clear on the difference sections (Figure 12). We use the *OOWC* picked on the baseline seismic to measure the mapped *RMS* amplitudes for the baseline, monitor 1 and monitor 2. A 10 ms window was used after testing the window size compared to the reservoir thickness (Figure 13). A displacement efficiency calculation was then performed for the picked *OOWC* using the approximation in equation (10). Unlike our previous synthetic data, this pick is not possible everywhere - Figures 13 shows the limits at which the pick is no longer visible due to tuning with the top reservoir. The resultant maps of displacement efficiency are shown in Figure 14 for each of the two monitors. Displacement efficiency for the first monitor period shows that oil is swept from the NW towards the well W1. The second monitor shows that after W2 was drilled, the Eastern side of the field is also being drained. The maximum efficiency is 65%, which is consistent with the 62% from SCAL measurements (Alvarez, 2014), indicating that water sweep of the light oil in this reservoir is fairly efficient, although there is still oil remaining. The results show that there are some small areas of low efficiency inside the confidence area (to the west and a small area in the NE) and also in the middle of the reservoir – based on well interference tests it is believed the latter are related to small baffling faults. Such regions could be potential targets for future *EOR*.

DISCUSSION

Application of our theory to observed seismic data has highlighted several points to be considered for future implementation of this technique. Firstly, the method for oil displacement efficiency described in this work is limited to seismic data for which the oil-water contact is clear and identifiable, and the contact movement can be readily resolved either on 3D or 4D seismic data. The oil-water contact is interpreted on 3D seismic data as an approximately flat amplitude event (flat spot) that is unconformable with the adjacent reflections and extends over an area bounded by the structural contours. However as the reflection coefficient at the *OWC* is almost an order of magnitude lower than the coefficients of the surrounding lithology contrasts (for example, 0.02 as opposed to 0.2), it is often hard to distinguish fluid contrasts and fluid changes in the presence of lithology changes and noise. Nevertheless, fluid contact interpretation can always be supported by well logs from control wells and then extrapolated across the field. The oil-water contact is more visible on high quality seismic data, and for thick reservoirs with good reservoir quality (i.e. high permeability, porosity and low shale or cement content, and younger sediments) and light oils with high API (30^o to 40^o). A moderate dip of the reservoir structure also helps in identifying the contact reflection. Factors that obscure detection include irregular illumination, multiples, imaging uncertainties due to velocity variations, lateral variations in facies or hydrodynamic gradients. Furthermore, fluid contacts are more likely to be visible in younger shallow reservoirs than old highly compacted reservoirs, for instance, fields such as Alba in the North Sea with Tertiary age sediments show a clear contact (Johnston 2013) whilst the Jurassic Gullfaks field exhibits a discontinuous oil-water contact (Landro and Stronen 2003). Exceptions to the trend of geological age include the impressive 9 km long oil-water contact observed in the Jurassic Troll field reservoir using 2D data (Brown 2011). According to the many published case studies in the literature, oil-water contact reflections are generally quite visible in seismic data from both clastics and carbonates, and for a range of sediment age, although we must often work hard to reveal their presence.

In 4D seismic data, changes in saturation are much more easily observed; as to observe distinct contact movement and the separate appearance of the produced oil-water contact there must be sufficient vertical movement (and reservoir thickness) to produce distinct reflections. In practice, there is greater contact movement if the vertical permeability is good, the reservoir volume is large, and the aquifer connectivity is high. An important observation is that even if fluid contacts are not visible on the 3D seismic data, it is still possible to observe and interpret them on the 4D difference data (Osdal et al. 2006, Staples et al. 2006, Alvarez, 2014). Indeed, water saturation-related changes are usually clearly observed in 4D seismic data, especially around water injectors or in areas of strong aquifer influx (for example, Johann et al. 2009). The technique proposed in our study can therefore also be used around water injectors (Obiwulu and MacBeth 2015). For low permeability reservoirs such as chalks (Byerely et al. 2006) the transition zone may be of significant thickness, and hence Figure 3 is no longer appropriate. Of concern for the method proposed in our study is a thin reservoir or small contact movement (i.e. less than 10 m in our current work). An example of this would be the Nelson field, for which the seismic wavelets from the produced and original contacts interfere at many locations (MacBeth et al. 2005). In the context of our study, the interpretation of interfering wavelets from each contact must attempt to unravel the composite effect of *ROS* on both amplitudes and time-shifts (Alvarez 2014). Such an approach could have benefit in refining vertical connectivity maps such as those of McLellan et al. (2006). The exact resolution will be strongly case-dependent.

Finally, it should be noted that the gas-water contact by comparison with the oil-water contact is bright (much higher reflection coefficient) and flat, and many clear case examples have been published, particularly from the Tertiary sediments of the Gulf of Mexico (Backus and Chen 1975, Brown 2011). Direct observation of hydrocarbon fluids from bright/flat spots is very well established in Tertiary clastic basins, of which the Gulf of Mexico is the most extensively studied, although there are also a large number in older reservoirs. Gas-water contacts in thick reservoirs in offshore clastic therefore provide the easiest targets, whilst other reservoirs represent a gradation of successively more elusive targets. Oil-water contact related flat spots are much less commonly seen than bright spots, and the majority of flat spots are gas-water contacts in gas reservoirs. The above suggests that further application for the technique proposed in our work could be to a gas reservoir and analysis of the remaining gas saturation. For this, a relation similar to (6) must be established – in the case of a gas-water or gas-oil contact, this is unlikely to be linear in saturation change.

CONCLUSIONS

A method to obtain estimates of the efficiency of water displacing oil in the hydrocarbon reservoir from 4D seismic is theoretically developed and tested in both synthetic and real data examples. This method does not require an in-depth analysis of the rock and fluid physics, therefore it is relatively simple and quick to apply on the data, requiring only the additional picking of fluid contacts on the datasets, and a calculation based on their amplitudes. The efficiency factor, $E_{D,}$ is linked to both the irreducible water saturation and the remaining oil saturation in the reservoir. The spatial distribution of E_D is one of the key quantities for reservoir management purposes and in particular is required for enhanced oil recovery programmes. The method uses estimates of the reflected amplitude at the observed oil-water contacts and requires visible fluid contacts in the 3D or 4D seismic data. Our approach extends the utility of 4D seismic data beyond the identification of bypassed oil to analyse the remaining oil in the already water-swept zones.

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APPENDIX A

To derive the seismic responses of the original and produced oil-water contacts we begin with Aki and Richards (1980) approximation expressed in terms of the elastic moduli κ, μ, M and ρ (bulk modulus, shear modulus, P modulus and density respectively) (Gray et al. 1999)

$$R(\theta) = \left[1 - \frac{4}{3}\left(\frac{\overline{V_S}}{\overline{V_P}}\right)^2\right] \Gamma_1 \frac{\Delta\kappa}{\bar{\kappa}} + \Gamma_2 \frac{\Delta\rho}{\bar{\rho}} + \left(\frac{\overline{V_S}}{\overline{V_P}}\right)^2 \Gamma_3 \frac{\Delta\mu}{\bar{\mu}} \ , \qquad \text{(A1)}$$

where

$$\Gamma_1 = \frac{1}{4}\sec^2\theta; \qquad \Gamma_2 = \frac{1}{2} - \frac{1}{4}\sec^2\theta \quad and \quad \Gamma_3 = \frac{1}{3}\sec^2\theta - 2\sin^2\theta \qquad \text{(A2)}$$

In this case, the reflectivity associated with the OOWC and POWC is from the fluid contrast and $\Delta\mu = 0$. Therefore

$$R(\theta) = \Gamma_1 \frac{\Delta\kappa}{\overline{M}} + \Gamma_2 \frac{\Delta\rho}{\bar{\rho}} \ , \qquad \text{(A3)}$$

Following Alvarez (2014), we calculate the rock and fluid variations in the bulk modulus and density across the interface within the limits of S_w =1 and S_w = S_{wirr} using the rock and fluid equations of Gassmann (1951) and Nur *et al.* (1995). Introducing the results into (A3), we obtain

$$R(\theta)_{OOWC} \approx \left\{-\Delta S_w^2 \frac{1}{2}\left(\frac{\emptyset}{\emptyset_C - \emptyset}\right)\left(\frac{\kappa_w - \kappa_o}{\kappa_{min} + \frac{4}{3}\mu_{min}}\right) + \Delta S_w\, 5\left(\frac{\emptyset}{1-\emptyset}\right)\left(\frac{\rho_w - \rho_o}{\rho_{min}}\right)\right\} sec^2\theta$$

$$+ S_{wirr}\left(\frac{\emptyset}{1-\emptyset}\right)\left(\frac{\rho_w - \rho_o}{\rho_{min}}\right), \qquad \text{(A4)}$$

and

$$R(\theta)_{POWC} \approx \left\{\Delta S_w^2 \frac{1}{2}\left(\frac{\emptyset}{\emptyset_C-\emptyset}\right)\left(\frac{\kappa_w-\kappa_o}{\kappa_{min}+\frac{4}{3}\mu_{min}}\right)+\Delta S_w \frac{1}{5}\left(\frac{\emptyset}{1-\emptyset}\right)\left(\frac{\rho_w-\rho_o}{\rho_{min}}\right)\right\} sec^2\theta$$

$$+ S_{wirr}\left(\frac{\emptyset}{1-\emptyset}\right)\left(\frac{\rho_w-\rho_o}{\rho_{min}}\right), \tag{A5}$$

Applying a first order Taylor expansion and defining $\Delta S_w^{OOWC} = 1 - S_{wirr}$ and $\Delta S_w^{POWC} = 1 - S_{oir} - S_{wirr}$, (A4) and (A5) reduce to:

$$R(\theta)_{OOWC} \approx a(1-S_{wirr}), \tag{A6}$$

and

$$R(\theta)_{POWC} \approx a'(1-ROS-S_{wirr}), \tag{A7}$$

where:

$$a = \frac{1}{2}\left\{\left(\frac{\emptyset}{\emptyset_C-\emptyset}\right)\left(\frac{\kappa_w-\kappa_o}{M_{min}}\right)+\left(\frac{\emptyset}{1-\emptyset}\right)\left(\frac{\rho_w-\rho_o}{\rho_{min}}\right)\right\} sec^2\theta \tag{A8}$$

and

$$a' = \frac{1}{2}\left\{\left(\frac{\emptyset}{\emptyset_C-\emptyset}\right)\left(\frac{\kappa_w-\kappa_o}{M_{min}}\right)-\left(\frac{\emptyset}{1-\emptyset}\right)\left(\frac{\rho_w-\rho_o}{\rho_{min}}\right)\right\} sec^2\theta \tag{A9}$$

Therefore, the ratio between the original and produced oil-water contacts is given by:

$$\left[\frac{R(\theta)_{POOWC}^{afer}}{R(\theta)_{OOOWC}^{before}}\right] \approx c\left[\frac{(1-S_{wirr}-ROS)}{(1-S_{wirr})}\right] \tag{A10}$$

where:

$$c \approx \frac{(\kappa_w-\kappa_o)\rho_w+\frac{3}{4}(\rho_w-\rho_o)\kappa_w}{(\kappa_w-\kappa_o)\rho_w-\frac{3}{4}(\rho_w-\rho_o)\kappa_w} \tag{A11}$$

or alternatively, using only the OOWC reflection:

$$\left[\frac{R(\theta)_{OOOWC}^{before}-R(\theta)_{OOOWC}^{after}}{R(\theta)_{OOOWC}^{before}}\right] \approx \left[\frac{(1-S_{wirr}-ROS)}{(1-S_{wirr})}\right] \tag{A12}$$

From where the displacement efficiency E_D can be calculated:

$$E_D = \left[\frac{(1-S_{wirr}-ROS)}{(1-S_{wirr})}\right] \quad \text{(A13)}$$